BEFORE THE

STATE OF DELAWARE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
DELMARVA POWER AND LIGHT COMPANY	)	
FOR APPROVAL OF MODIFICATIONS	)	PSC Docket No. 11-318F
TO ITS GAS COST RATES	)	
(Filed August 31, 2011)	)	

DIRECT TESTIMONY OF

ANDREA C. CRANE

ON BEHALF OF

THE DIVISION OF THE PUBLIC ADVOCATE

February 28, 2012

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and your business address.

A. My name is Andrea C. Crane and my business address is 90 Grove Street, Suite 211, Ridgefield, CT 06877. (Mailing address: PO Box 810, Georgetown, CT 06829)

Q. By whom are you employed and in what capacity?

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation and regulatory policy. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various financial studies relating to utility rates and regulatory policy. I have held various positions of increasing responsibility with The Columbia Group, Inc. since January 1989. I became President of the firm in 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in over 350 proceedings in the states of Delaware, Arkansas, Arizona, Connecticut, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia, and the District of Columbia. These proceedings involved gas, electric, telephone, water, wastewater, solid waste, cable television and navigation utilities. A list of dockets in which I have filed testimony since January 2008 is included as Appendix A.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On August 31, 2011, Delmarva Power and Light Company ("Company" or "DPL") filed an Application with the State of Delaware, Public Service Commission ("PSC" or "Commission") requesting approval for a change in the annual commodity cost rate and the annual demand cost rate components of its Gas Cost Rate ("GCR") factor for the period November 1, 2011 through October 31, 2012.

The Columbia Group, Inc. was engaged by the State of Delaware, Division of the Public Advocate ("DPA") to review the Company's proposed GCR rates, to identify areas of possible concern to Delaware ratepayers, and to develop recommendations for consideration by the Commission. In developing my recommendations, I reviewed the Company's Application, the testimony and exhibits filed by the Company, and the responses to data requests propounded upon DPL by the DPA and by the Staff of the Public Service Commission ("Staff"). I also reviewed prior PSC orders and other documents useful in an analysis of the Company's filing.

III. SUMMARY OF CONCLUSIONS

Q. Please summarize your conclusions and recommendations.

A. Based on my review of DPL's Application, on its testimony and exhibits, on its discovery responses, and on my experience in the area of regulatory accounting and policy, my conclusions and recommendations are as follows:

- The Company should continue to use the National Oceanic and Atmospheric Association ("NOAA") thirty-year weather normal unless NOAA adopts a different methodology for forecasting purposes.
- The Company should continue to execute the gas hedging plan approved in PSC Docket No. 08-266F, subject to modifications that may be agreed upon by the parties during the quarterly gas hedging meetings.
- DPL should continue to monitor its capacity pipeline agreements and storage contracts and should terminate agreements and contracts that are expiring, if possible, in order to reduce its capacity reserve margin.

- The PSC should continue to monitor DPL's loss factor for reasonableness.
- The GCR rates requested in the Application should be approved, subject to a true-up in DPL's next GCR filing based on actual gas procurement costs and recovery revenues during the period November 1, 2011 to October 31, 2012.

IV. BACKGROUND OF THE APPLICATION

Q. Please provide a brief background of the Company's filing.

A. On August 31, 2011, DPL filed its GCR factors for the period November 1, 2011 through October 31, 2012. The Company requested the following modifications in rates:

	Prior Demand Charge	Prior Commodity Charge	Proposed Demand Charge	Proposed Commodity Charge
RG,GG, and GL	N/A	$0.94042/Ccf	NA	$0.88804/Ccf
Non-electing MVG	$12.0266/Mcf Billing MDQ	$7.5811/Mcf	$11.0936/MCF Billing MDQ	$7.1740/Mcf
Electing MVG and LVG	$12.0266/Mcf Billing MDQ	Varies	$11.0936/MCF Billing MDQ	Varies
Standby Service	$12.0266/Mcf Billing MDQ	N/A	$11.0936/Mcf Billing MDQ	NA

In its filing, the Company also proposed to reconcile and true-up actual versus estimated Commodity Cost Rate assignments for LVG and electing MVG customers.

On September 20, 2011, the PSC issued Order No. 8040, allowing the GCR factors to become effective with meter readings on and after November 1, 2011, with proration, on a provisional basis subject to refund. The rates proposed in the Application resulted in a GCR decrease of 5.6% for RG, RSH, and GL customers. Residential space heating customers using 120 Ccfs in a winter month experienced decreases of $6.29 or 3.7% in their total bill. Customers served on Service Classifications GG experienced decreases of 2.1% to 4.3% on their winter bills. Non-electing MVG customers experienced decreases in their winter bills of 4.3% to 4.9, depending on usage characteristics.

Q. Is the Company's GCR calculation in this case unusual in any way?

A. Yes, it is. The GCR calculation generally seeks to recover estimated gas costs during the prospective determination period, in this case for the period November 1, 2011 through October 31, 2012. In addition, the GCR is designed to true-up actual over/under recoveries for the prior twelve month period. In its Application in its last GCR filing, PSC Docket No. 10-295F, DPL projected that its GCR clause would be under-recovered by approximately $24.5 million at October 31, 2010, the beginning of the determination period in that case. Given the significant projected under-recovery, DPL proposed to amortize this under-recovery, as well as interest on the under-recovery, over a period of two years. DPA did not oppose the Company’s request to recover the deferred gas costs over two years, but recommended that the Company’s proposal to collect $342,307 of interest on this amount be denied. This recommendation was based on the fact that the large under-recovery was due to DPL having hedged a very high percentage of its gas costs at rates that turned out to be significantly higher than the market. In the Settlement Agreement in Docket No. 10-295F, the parties agreed that DPL could recover its deferral over two years, but that the Company would not collect interest on this deferral. Thus, the rates proposed in this case include the second year of the amortization relating to the deferral of gas costs for the twelve months ending October 31, 2010. In addition, the Company's filing includes a credit to interest of $171,000 relating to the prior deferral.

Q. What recommendations did you make in the Company's last GCR filing, Docket No. 10-295F?

A. My testimony in that case contained the following recommendations:

- I recommend that the Company should continue to use the National Oceanic and Atmospheric Association ("NOAA") thirty-year weather normal unless NOAA adopts a different methodology for forecasting purposes.
- Given that the October 31, 2010 under-recovered balance was driven by the Company's hedging decisions, which resulted in ratepayers paying millions of dollars in above-market gas costs, I recommended that the PSC deny the Company's request to recover $342,307 of interest on this under-recovery.
- I recommended that in its next GCR filing, DPL should be required to provide information to the parties regarding the capacity pipeline agreements that have expired, or that will expire during the 2011-2012 determination period. In addition, I recommended that the Company should be required to

justify any decisions to extend the term of any pipeline capacity agreements that would otherwise have expired.

- I recommended that the PSC base the amount collected from DPL ratepayers relating to the Eastern Shores EnergyLink Expansion (“E-3”) Project surcharge on DPL’s most recent authorized rate of return.
- I recommended that capacity release revenues and off-system sales margins be allocated between shareholders and ratepayers consistent with the Settlement Agreement in PSC Docket No. 08-266F.
- I recommended that the PSC continue to monitor DPL's loss factor for reasonableness.
- I recommended that if the PSC approved the Company's pending decoupling proposal, then the parties should monitor budget billing among the Company's ratepayers to determine what, if any, impact the new rate structure has on the use of budget billing.
- In evaluating the net benefits to be shared between shareholders and ratepayers with regard to the Company's Asset Management Agreement, I recommended that the PSC take into consideration any increase in gas commodity costs resulting from the sale of the Company's gas inventory associated with that agreement.
- I recommended that DPL be required to comply with the terms of the Settlement Agreement in PSC Docket No. 09-385F relating to asset

management activities, including notifying the parties when it issued future Requests for Proposal for asset management services.

- I recommended that the GCR rates requested in the Application be approved, subject to a true-up in DPL's next GCR filing based on actual gas procurement costs and recovery revenues during the period November 1, 2010 to October 31, 2011, subject to the adjustments relating to a) interest on the deferral and 2) E-3 precertification costs, as discussed above.

Q. How were the issues that you raised in the last case resolved?

A. The Company's last GCR proceeding was resolved by a Stipulation that was approved by the PSC in Order No. 8060, issued October 18, 2011. The primary provisions of that stipulation included:

1. The parties agreed to approve DPL's requested GCR rates, and to amortize the projected deferred balance over two years.
2. DPL agreed to reduce its GCR by $171,000 each year for two years relating to interest on its deferral for the twelve months ending October 31, 2010.
3. The parties agreed to discuss the potential to amortize further deferrals over a period exceeding one year.
4. DPL agreed to undertake several engineering studies relating to its Liquefied Natural Gas ("LNG") facility.
5. DPL agreed to continue to execute its gas hedging program.

6. DPL agreed to notify the parties prior to entering into any asset management agreement that involved the assignment or transfer of more than 25% of its total supply portfolio to one single manager.

7. The parties agreed that DPL could recover E-3 costs, based on a revised payment schedule. This revised payment schedule reduced the amortization period (and associated interest expense) and allocated a share of the deferred tax benefit to DPL. Each of these revisions resulted in significant savings to ratepayers.

8. DPL agreed to evaluate its portfolio of capacity and to keep the parties informed about its plans with regard to contracts that were nearing their termination date.

9. DPL agreed to include testimony in its next GCR case about how it plans to meet the requirements of 26 *Del. C.* §1502 relating to reducing gas usage.

V. DISCUSSION OF THE ISSUES

A. Projected Sales Forecast

Q. What level of customer growth has the Company experienced over the past ten years?

A. Shown below is the customer growth and total sales experienced by the Company since 2002:[1]

1 Responses to DPA-12 and DPA-13.

Year (Average)	Total Customers	Customer Growth	Total Sales (Mcfs)
2011 (thru 10/31/11)	123,348	0.46%	10,290,387
2010	122,783	0.36%	12,478,433
2009	122,342	0.29%	12,655,382
2008	121,986	0.44%	13,148467
2007	121,450	1.00%	13,841,809
2006	120,242	1.33%	12,790,842
2005	118,665	1.20%	14,983,983
2004	117,263	1.15%	15,092,730
2003	115,930	1.65%	16,564,451
2002	114,048	1.88%	14,201,904

Prior to 2008, annual customer growth averaged approximately 1.5%, which is in line with the experience of other gas utilities. Beginning in 2008, the annual growth in customers declined substantially. This decline is not surprising, given the deterioration of the housing market, tightening of the credit market, and the overall decline in business activity.

Q. How did the Company develop its sales forecast used in this filing?

A. The Company's sales forecast for smaller customers is based on a multi-variant regression analysis that seeks to establish the relationship among customer growth, economic activity, weather, commodity prices, and gas consumption. To define normal weather, the Company uses a thirty-year average of monthly Heating Degree Days ("HDDs"). The thirty-year normal is the standard established by NOAA, which is the governmental body charged with maintaining and analyzing climate data. Volumes for MVG, LVG, and GL customers were projected deterministically on a customer-by-customer basis.

Q. Do you agree with the use of the thirty-year NOAA normal for purposes of forecasting sales during the GCR determination period?

A. Yes, I do. The NOAA thirty-year normal is an objective standard promulgated by the U.S. Government organization that is responsible for climatic records and policy. Therefore, the NOAA thirty-year standard is the appropriate standard for utilities to use for purposes of determining the impact on utility rates, including the GCR.

Q. What level of sales is DPL forecasting for the upcoming GCR period?

A. As stated on page 2 of Mr. Brielmaier's testimony, DPL is forecasting firm sales of 12,946,388 Mcfs for the period November 1, 2010 through October 31, 2011. In addition, DPL is forecasting firm transportation sales of 6,640,926 Mcfs, for a total firm throughput of 19,587,314 Mcfs.

B. Projected Gas Commodity Costs

Q. Please summarize the components of the RG, GG, and GL GCR rates requested by the Company in its Application.

A. Following are the components of the RR, GG, and GL GCR rates requested by DPL in its Application:

	Original ($ / Mcf)
Commodity Component	$5.6579
Demand Component	$1.6732
Demand True-up	$0.0332
Commodity True-up	$1.5161
Total Rate	$8.8804

Q. How did the Company determine the commodity price of gas used in the GCR Application?

A. The Company's projected commodity cost is based on three components, as shown on page 8 of Mr. Giovannini's testimony: 1) natural gas withdrawn from storage, 2) gas that is currently hedged for the 2011-2012 determination period, and 3) gas that is purchased on the "spot" market. As noted by Mr. Giovannini, storage withdrawals, hedged purchases, and spot purchases are projected to make up approximately 25.0%, 32.7%, and 42.4% respectively of the Company's estimated commodity requirements for this period.[2]

Q. How do the estimated prices of these three sources compare with one another?

A. As shown in Table 1 of Mr. Giovannini's testimony, hedged volumes have an estimated cost of $7.18 per Mcf, while storage withdrawals have an estimated cost of $4.98. The average projected cost for spot gas is $4.43 per Mcf.

2 Numbers do not add due to rounding.

Q. How did the Company determine the estimated cost of spot market gas used in its GCR Application?

A. The Company based its commodity price forecast on the NYMEX futures closing prices at August 4, 2011. This methodology is consistent with the Stipulation in Docket No. 05-312F. In that Stipulation, DPL agreed to use NYMEX futures prices in future cases, unless it could show good cause why another method should be employed.

Q. How do the NYMEX futures prices reflected in the Application compare with current market prices?

A. Market prices for natural gas have continued to fall since the Company filed its Application, as shown below:

Month	NYMEX 8/4/11[3]	NYMEX 2/27/12
November 2011	$4.2332	
December 2011	$4.4474	
January 2012	$4.5519	
February 2012	$4.5571	
March 2012	$4.5302	$2.550
April 2012	$4.4836	$2.695
May 2012	$4.5095	$2.808
June 2012	$4.5468	$2.902
July 2012	$4.5902	$2.973
August 2012	$4.6192	$3.010
September 2012	$4.6275	$3.020
October 2012	$4.6637	$3.071

3 Per the response to DPA-29.

Although commodity prices have declined, I am not recommending any adjustment to the Company's proposed GCR factors as a result of this decline. While gas commodity prices are lower than those projected in DPL's Application, the weather in the Company's service territory has been very mild this winter. Therefore, the Company's gas sales are likely to be significantly less than projected in the Application. Lower sales will make it more difficult for DPL to recover its demand costs, which are generally fixed and do not vary with variations in sales. Based on more recent commodity price and gas sales estimates, DPL currently projects that by the end of the determination period, its deferred balance will be within the 6% benchmark utilized by the PSC.

C. <u>Gas Hedging Program</u>

Q. Please provide a brief description of the Company's Gas Hedging Program.

A. Prior to the Stipulation in PSC Docket No. 08-266F, DPL operated under a very flexible program that provided considerable latitude to the Company to decide when to hedge and how much of its firm supply requirements to hedge. The previous Gas Hedging Program guidelines required that the Company hedge 10% of its firm requirements load 18 months in advance, 20% of its load 12 months in advance, and 30% of its load 6 months in advance. There was also a 70% maximum target, but that maximum was discretionary, i.e., the guidelines did not prohibit DPL from hedging more than 70% of its firm supply requirements. Unfortunately, the Company chose to hedge amounts exceeding 70% during a time of increasing gas prices. This meant that as prices subsequently started to fall, the Company was already locked in to purchases at prices that far exceeded market prices.

The results for the Company's hedging activities had been relatively good until the fourth Quarter 2008, when the cost of gas purchased pursuant to the Company's hedging instruments exceeded the NYMEX settle prices by approximately $9.2 million. The results for 2009 and 2010 were even worse, with the Company's hedged gas exceeding market prices by $55.15 million and $28.79 million respectively.

As a result of concerns raised in PSC Docket No. 08-266F, the parties agreed that DPL would implement changes to its Gas Hedging Program. The parties agreed to a formulistic approach whereby the Company would hedge 50% of its city gate supply requirements over a one year period, with 1/12th to be hedged each month. Specifically, the Stipulation in PSC Docket No. 08-266F contained the following provisions relating to the Gas Hedging Program:

> After negotiations and consultations, the parties have agreed that Delmarva will revise its hedging program. Six gas hedging provisions or guidelines were approved by the Commission in Delaware PSC Docket No. 00-463F. The first two guidelines established 1) a minimum level of hedging and 2) an overall target level of hedging, as previously addressed above. Pursuant to this agreement, those two guidelines will be replaced by a fifty percent (50%) non-discretionary hedging program in which 50% of projected city gate requirements and storage injections are to be hedged on a pro rata basis (1/12th each month) over the 12-months preceding the month in which the physical gas is to be delivered to customers. Except in the event of extraordinary circumstances as set forth below, the hedging program set forth in this paragraph will be conducted without regard to anticipated price trends.
>
> The parties acknowledge that the implementation of the new hedging program will take place over time due to pre-existing hedging positions which may, in some months, be outside the parameters of the new hedge program.

> If, in the exercise of its business judgment, the Company believes there are extraordinary circumstances that may warrant varying from the hedging program agreed to herein, the Company will seek the agreement of Staff and Public Advocate to temporarily modify the hedge amounts from the fifty percent (50%) or 1/12th monthly requirements. Staff and Public Advocate will analyze the request and either agree or request its expedited consideration by the Commission.
>
> The Company agrees to file its Quarterly Hedging Report within 30 days following the close of the quarter.
>
> The parties agree that the 50% non-discretionary program agreed to herein is subject to alteration should it provide unsuccessful in future years.

Q. Has the Company complied with these provisions?

A. As noted by the Stipulation, the new provisions of the Gas Hedging Program were required to be phased-in, due to the fact that the Company had already exceeded the 50% hedging limit required pursuant to the new Gas Hedging Program. Therefore, the Company did not take any new positions until December 2010. Since the Stipulation in PSC Docket No. 08-266F was executed, DPL has been providing quarterly reports on its Gas Hedging Program and has met with the parties each quarter to review its actual results. For the first nine months of 2011, the Company's costs for hedged gas exceeded market prices by $16.19 million. For the current GCR period, the Company expects its hedge costs to exceed market prices by $12.88 million. Losses will continue at least until March 2013, when the positions taken prior to the changes in the hedging program will expire. In addition, the excess of hedged costs over market prices has been impacted by the fact that market prices have continued to fall.

Q. What steps have the parties taken in response to declining market prices for natural gas?

A. In response to declining market prices, the parties agreed that DPL should accelerate purchases of hedged volumes for its winter heating season. On December 1, 2011, the parties entered into an agreement for a temporary modification of the gas hedging program to permit DPL to hedge up to 75% of its projected supply requirements for the months of January and February 2012. In addition, the parties recently discussed a further drop in the market for natural gas and agreed that the Company should accelerate purchases of 50% of its projected supply requirements through October 2012.

Q. Do you have any other comments about the Company's gas hedging program?

A. Yes, it should be noted that since the hedging guidelines were revised, the parties have met quarterly to discuss the results of the hedging program. Communications with DPL are now very good. DPL has kept the parties informed not only about the hedging program but also about changes in the gas market. While the parties recognize that it will still be some time before all of the hedges taken under the old program expire, I believe that the new hedging program is working well. I am especially encouraged about the openness of DPL and the relationship that the Company has developed with DPA and Staff relating to procurement activities.

D. Capacity Requirements and Capacity Costs

Q. How does the Company generally develop its design day demand forecast?

A. The Company's design day forecast is based on a regression analysis using data from the previous winter heating season. That data is then extrapolated to a 65 HDD and an average design day usage factor is determined. The design day usage factor is then applied to the forecast of customers to determine peak day demand for smaller customers. Historic loads are generally used for larger customers. The Company forecasts a design winter based on weather that is 10% colder than a thirty-year normal.

Q. Did the Company project a design day shortfall up until 2009?

A. Yes, for many years prior to the addition of new pipeline capacity in December 2008, DPL reported capacity shortfalls relative to its peak day supply requirements. As a result of these projected shortfalls, DPL subscribed to 25,000 Dths/day from the Transco Sentinel Expansion Project. This capacity went into service on December 21, 2008.

Unfortunately, after acquiring this capacity, DPL lost several large industrial customers. These losses, coupled with the general economic slowdown, has negatively impacted sales. According to page 12 of Mr. Giovannini's testimony, DPL has firm supply deliverability of 192,775 Mcfs for the winter of 2011-2012, 11.4% higher than its projected design day requirement of 173,008.

Q. Has DPL experienced design day conditions at any time over the past few years?

A. No, it has not. The Company's actual peak day demand has generally been well below its projected design day demand. Following is the actual peak day demand in each of the past five GCR periods:[4]

Winter Season	Actual Peak (Mcfs)
2010/2011	125,276
2009/2010	126,551
2008/2009	142,164
2007/2008	124,424
2006/2007	148,046

The Company is not projecting a need for additional capacity for several years. In fact, given the large reserve that DPL now has, DPA recommended in the last GCR proceeding that the Company explore terminating some of its capacity agreements. As discussed on pages 2-3 of Mr. Giovannini's testimony, DPL has taken steps to terminate two capacity contracts and one storage contract. In addition, DPL has evaluated its capacity portfolio and has reviewed the results of this evaluation with DPA and Staff. DPL should continue to evaluate its portfolio as contracts expire in order to minimize the fixed costs that must be borne by ratepayers.

Q. How are capacity release revenues and off-system sales margins shared between shareholders and ratepayers?

4 Response to DPA-10.

A. As a result of the Settlement Agreement in PSC Docket No. 08-266F, ratepayers receive the first $3.0 million of capacity release revenues and off-system sales margins. The margin sharing for capacity release revenues and off-system sales margins above that amount are allocated 80% to ratepayers and 20% to shareholders.

Q. What are the historic levels of capacity release revenues and off-system sales margins received by the Company over the past few years?

A. The Company has received the following revenue relating to capacity releases and off-system sales margins:

GCR Period	Capacity Release Revenue	Off-System Sales Margins	Margins To Ratepayers
2010/2011	$4,150,478	$2,526,479	$6,182,208
2009/2010	$3,972,591	$1,108,994	$4,230,250
2008/2009	$6,934,093	$2,080,682	$7,742,770
2007/2008	$5,407,600	$5,300,772	$8,906,712
2006/2007	$5,919,412	$2,206,902	$6,841,051

Q. What level of capacity release revenues and off-system sales margins is the Company proposing in this case?

A. In its filing, the Company included GCR credits of $2,988,278 for capacity release revenues and of $2,695,319 for off-system sales margins, as shown on Schedule JBJ-5, page 2 to Mr. Jacoby's testimony. This reflects total Company capacity release revenues of $3,336,947 and off-system sales margin revenues of $3,080,982 for the period November 2011 to

October 2012, as shown in Mr. Giovannini's testimony at Schedule MG-3.

E. Loss Factors

Q. What loss factor has DPL used in its filing?

A. The Company's filing is based on a loss factor of 2.0%.

Q. How does the loss factor compare with actual results?

A. According to Mr. Brielmaier's testimony at page 5, the actual rolling twelve-month average loss factor through June 2011 was 2.2%, while the twenty-four month average was 2.0% and the thirty-six month average was 2.3%.

Q. Are you recommending any adjustment to the loss factor used in Company's filing?

A. No, I am not. The loss factor proposed by DPL appears reasonable given historic results. Moreover, costs resulting from the loss factor are essentially trued-up through the annual true-up process. Therefore, ratepayers will ultimately pay rates that reflect the actual losses incurred by the Company during the GCR year. I do recommend that the PSC continue to monitor the Company's actual percentage of losses to determine if any adjustment to the 2.0% loss factor is warranted in a future GCR proceeding.

F. Gas Cost Rate Recommendation

Q. What was the Company's actual deferred balance at October 31, 2010?

A. In its GCR filing, the Company projected that it would be under-recovered by approximately $19.76 million at October 31, 2011. According to the Company's response to DPA-21, the Company was actually under-recovered by $21.88 million.

Q. Are you recommending any adjustment to the Company's proposed GCR rates?

A. No, I am not. As discussed above, commodity costs have declined since the Company filed its Application. However, due to the mild winter weather, gas sales have been below projections and, as noted, the Company's actual deferred balance at October 31, 2011 was approximately $2.12 million higher than projected. The GCR true-up process provides a reconciliation between actual and projected natural gas costs and recoveries. Moreover, by the hearing phase in this case, the 2011-2012 winter heating season will be largely behind us. Therefore, I am not recommending any revision to the rates that were approved on a provisional basis by the Commission in this case. However, these rates should be subject to a true-up in DPL's next GCR filing based on actual gas procurement costs and recovery revenues for the twelve months ending October 31, 2012.

Q. Does this conclude your testimony?

A. Yes, it does.